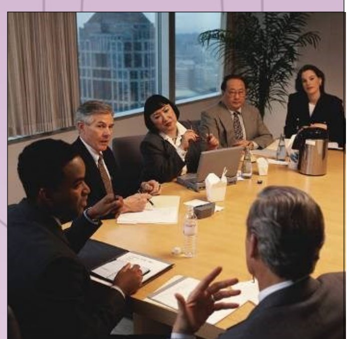

Benefit-Cost Analysis for Advanced Metering and Time-Based Pricing

Final Workshop
January 15, 2008

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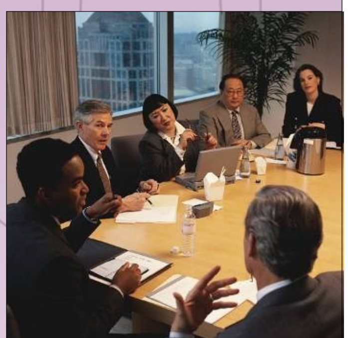
Workshop Objectives and Agenda

- Workshop objective
  – Present the final results of our analysis of the costs and benefits of AMI and time-based pricing in Vermont
- Workshop agenda
  – Methodological summary
  – Recent developments—Energy Independence & Security Act
  – Statewide summary
  – Utility-specific analysis
  – Rate design issues and policy options
  – Conclusions and recommendations



Overview of Methodology and Analysis Approach

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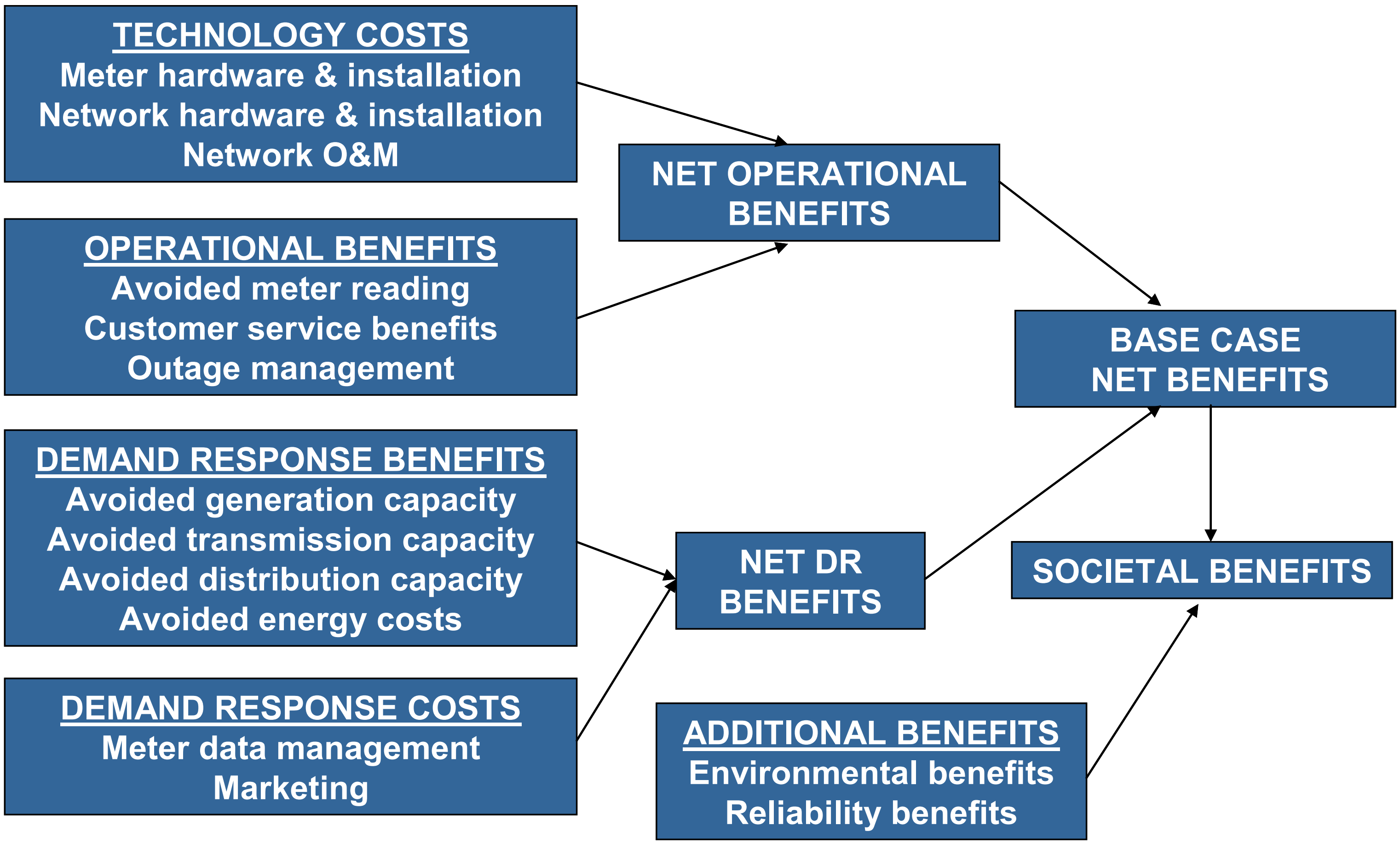
The analysis was completed for 10 of Vermont's 20 utilities

- Separately for CVPS, GMP, VEC, BED & WEC
  - VEC is already installing AMI meters so the analysis only looked at demand response costs and benefits
- Jointly for Hardwick, Lyndonville, Stowe, Morrisville and Ludlow
- Collectively, these utilities account for 96% of Vermont's electricity customers and 93% of Vermont's load

Cost-effectiveness analysis requires examining costs, operational benefits and demand response benefits



The analysis involved three primary work streams

- AMI technology selection and cost analysis
  - Examined the costs associated with multiple technology options, all of which met the minimum requirements of two-way communication and daily delivery of hourly data
  - Chose the least cost option for each utility
- Operational benefit analysis
  - Examined a limited set of benefits, with avoided meter reading costs being the dominant one
- Demand response analysis
  - Estimated DR benefits (avoided G, T & D capacity and change in energy costs)
  - Estimated DR costs (marketing and data management)

The technology analysis examined five cost streams

COST OF ADVANCED METER INFRASTRUCTURE

=

INITIAL METER DEPLOYMENT EQUIPMENT & INSTALLATION COSTS + NETWORK DEPLOYMENT +

INCREMENTAL COST OF NEW & REPLACEMENT METERS IN FUTURE YEARS + NETWORK OPERATIONS + NETWORK MAINTENANCE

Key Operational Savings Categories

- Avoided meter reading costs
  - Labor and overheads for meter readers and supervisors
  - Avoided vehicle and other equipment costs
  - Savings are offset by severance costs
- Field operations
  - Reduced "no light" calls
  - Reduced storm restoration costs
- Call center
  - Fewer bill complaints from estimated bills
- Reduced meter O&M costs during warranty period
  - Normal O&M avoided in all future years and counted as a benefit
  - O&M for new meters is included on the cost side of the ledger with $0 costs during warranty period

The financial benefits associated with DR are estimated as follows

Δ Peak Period Energy Use on High Demand Days x Market Price of Generation Capacity x Generation Performance Factor = Generation Capacity Benefits

Δ Peak Period Energy Use on High Demand Days x Marginal Cost of T&D Capacity x T&D Performance Factor = T&D Capacity Benefits

Δ Peak Period Energy Use x Wholesale Energy Costs During Peak Period - Δ Off-Peak Energy Use x Wholesale Energy Costs During Off-Peak Period = DR Energy Benefits

TRC+ Analysis

- Two additional benefit streams were examined but not included in the base case analysis
  - Environmental benefits
  - Reliability benefits stemming from reduced outage costs due to reductions in average outage duration
- The environmental benefits are quite small because the change in energy use is quite small
  - 0.87 cents/kWh
- The reliability benefits are discussed further on the next two slides

Publicly available data on the impact of AMI on outage duration is limited

- Vendor claims are usually for advanced distribution infrastructure systems (ADI), a complement to AMI
- Claim outage reduction up to 35% - used as an upper bound for AMI without ADI
- Employ a conservative outage reduction (5%) in valuation
- Calculate value of avoided costs under multiple scenarios

Graph Source: GE's Advance Distribution Infrastructure Solutions

Avoided outage costs = costs with current average outage durations – costs with reduced outage durations

- Used residential and commercial customer damage functions found in
  - *A Framework and Review of Customer Outages* (LBNL- 54365)
  - The study pooled ~30 value of service studies from across the U.S. for a comprehensive study of outage costs
  - Regression functions allow users to develop customized outage cost estimates
- Key inputs include:
  - Average outage frequency and duration as indicated by the reliability indices provided in response to the DPS data request.
  - Average annual kWh by customer type
  - Outage onset
  - Average residential household income (from VT Indicators Online)
  - # of employees assumed to be 10 for medium customers and 100 for medium-large customers
- Large (>200kW) Industrial customers were excluded since their outage costs vary widely as a function of detailed inputs that were not readily available (e.g., industry type, backup generation, power conditioning equipment, etc)

Recent Developments: Energy Independence and Security Act of 2007

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Main Sections Addressing DR, AMI and Smart Grid

- Section 529 – National DR Assessment and Action Plan
- Section 532 – Additional State Considerations (PURPA Standards)
- Section 1301 – Statement of Policy
- Section 1302 – Report on Smart Grid Deployments
- Section 1303 – Federal Advisory Committee and Task Force
- Section 1304 – Technology RD&D
- Section 1305 – Interoperability Framework
- Section 1306 – Federal Matching Fund
- Section 1307 – State Considerations (PURPA Standards)
- Section 1309 – Study of Security Attributes

Section 1506 – Matching Grants

- New DOE Program to provide reimbursement of 20% of smart grid investments
- Procedures published within one year
- Authorization of such sums as necessary
- Eligible Investments
  - Manufacture of Efficient Appliances
  - Modifying special electricity equipment, e.g. motors
  - Utility installment of Smart Grid-enabled T&D infrastructure
  - Purchase and installation of metering and control devices and equipment
  - Software to enable computers to engage in smart grid functions

Section 1307 – State Considerations

- Two new “Standards” created under the Public Utilities Regulatory Policy Act (PURPA)
- Smart Grid Investments
  - Utilities must consider smart grid investments before proceeding with “traditional” investments
  - Utilities are authorized to recover costs of smart grid investments
  - Utilities are authorized to recover remaining book value of infrastructure made obsolete
- Smart Grid Information
  - Customers shall be provided direct access, in writing or electronically, to information including:
    - Prices
    - Usage
    - Intervals and projections
    - Sources and emissions

Section 1307 – State Considerations (continued)

- Section is built on the "PURPA Construct"
  - No direct mandate to do
  - Requirement is to consider
  - Not just State Commissions
  - Commence a proceeding or set a hearing date within 1 year
  - Complete consideration and make determination within 2 years

Statewide Summary

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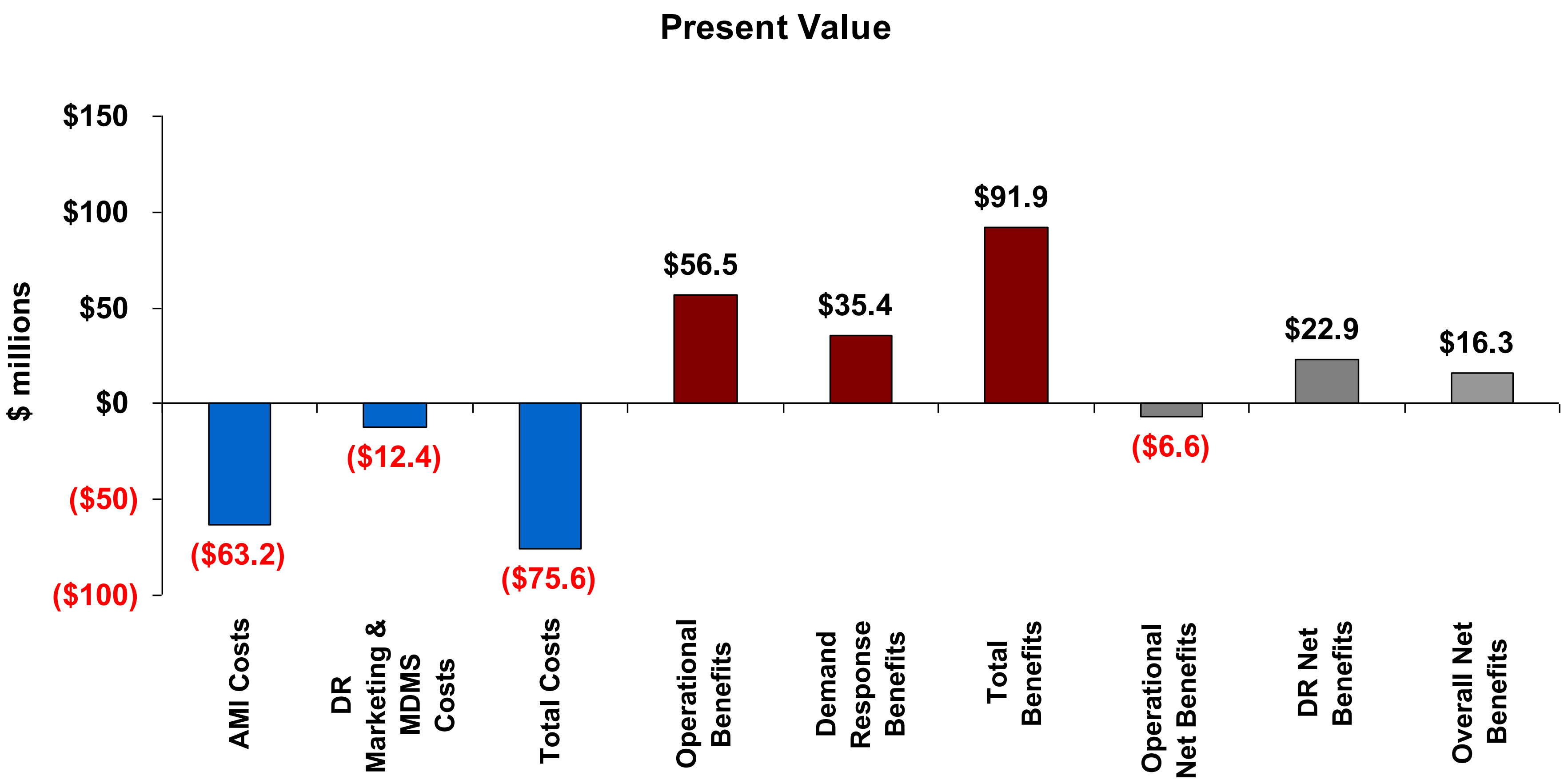
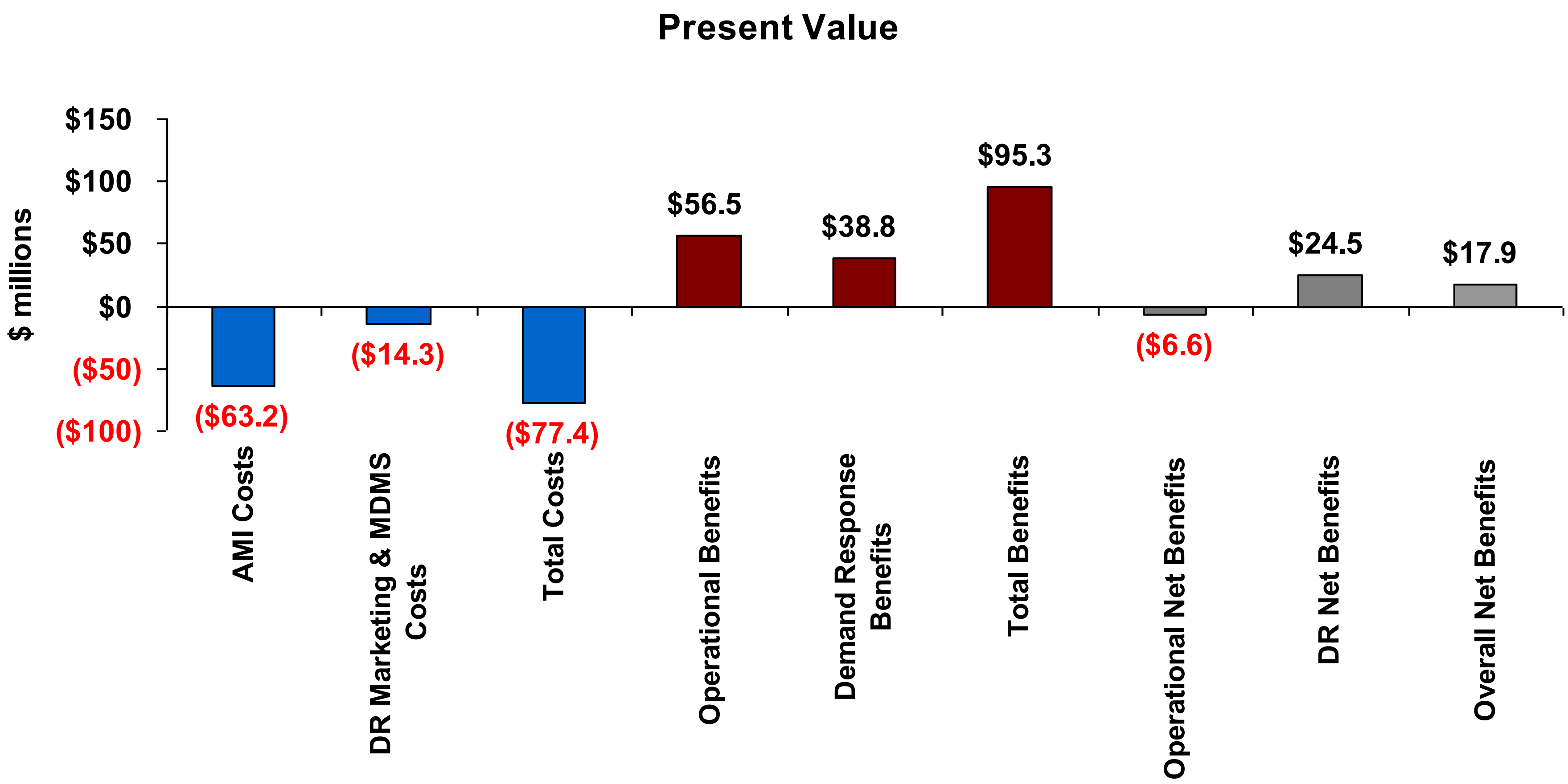
Preliminary results are based on the following

- Mesh is the least cost option for everywhere but WEC, where PLC had the lowest cost
  - There were typically not large differences in costs across technology options
- We assumed that CVPS and GMP would purchase an MDMS system, whereas VEC, BED, WEC and the small utilities would outsource this functionality
- Base case is a PTR program with a 75 ¢/kWh adder, 50% awareness rate for residential customers and a 25% awareness rate for commercial customers
- VEC analysis only included DR benefits & costs
  - Present statewide results with and without VEC where appropriate

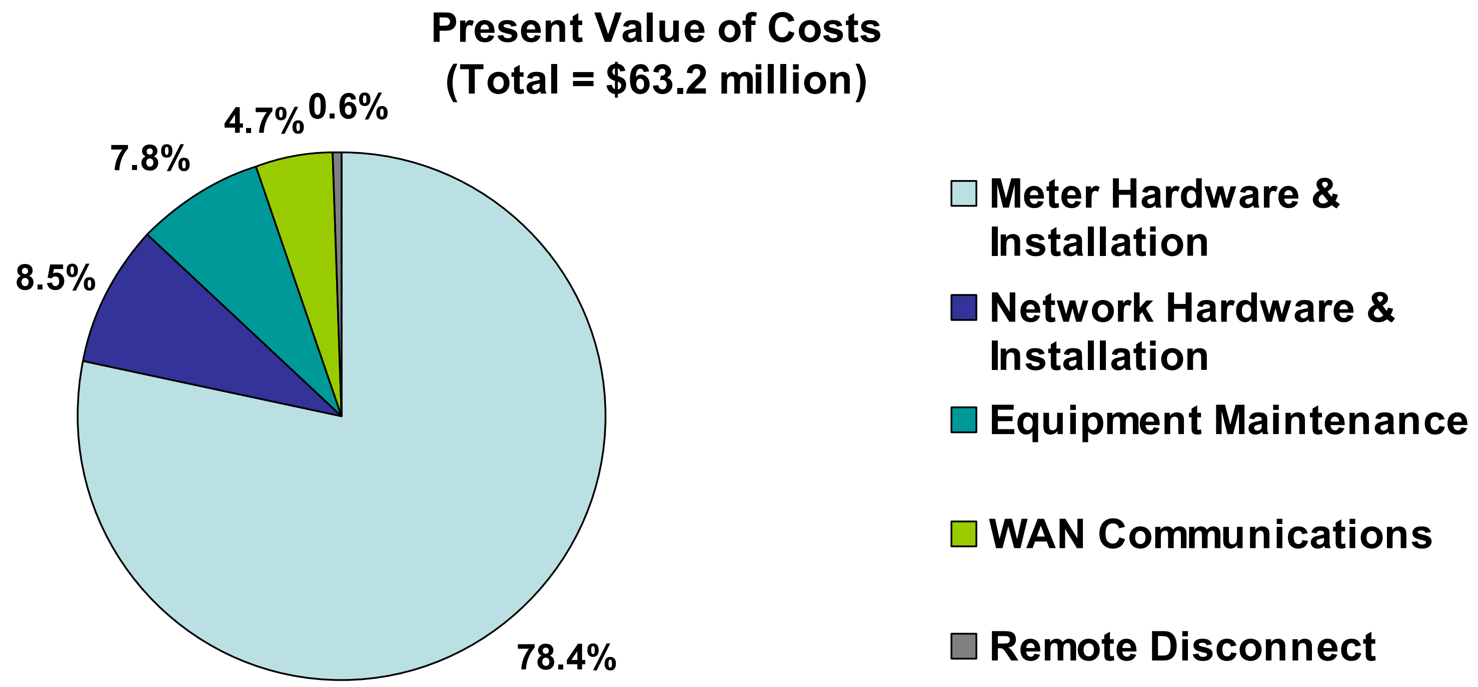
Without VEC, operational net benefits are negative but overall net benefits are strongly positive—the overall negative is due primarily to GMP



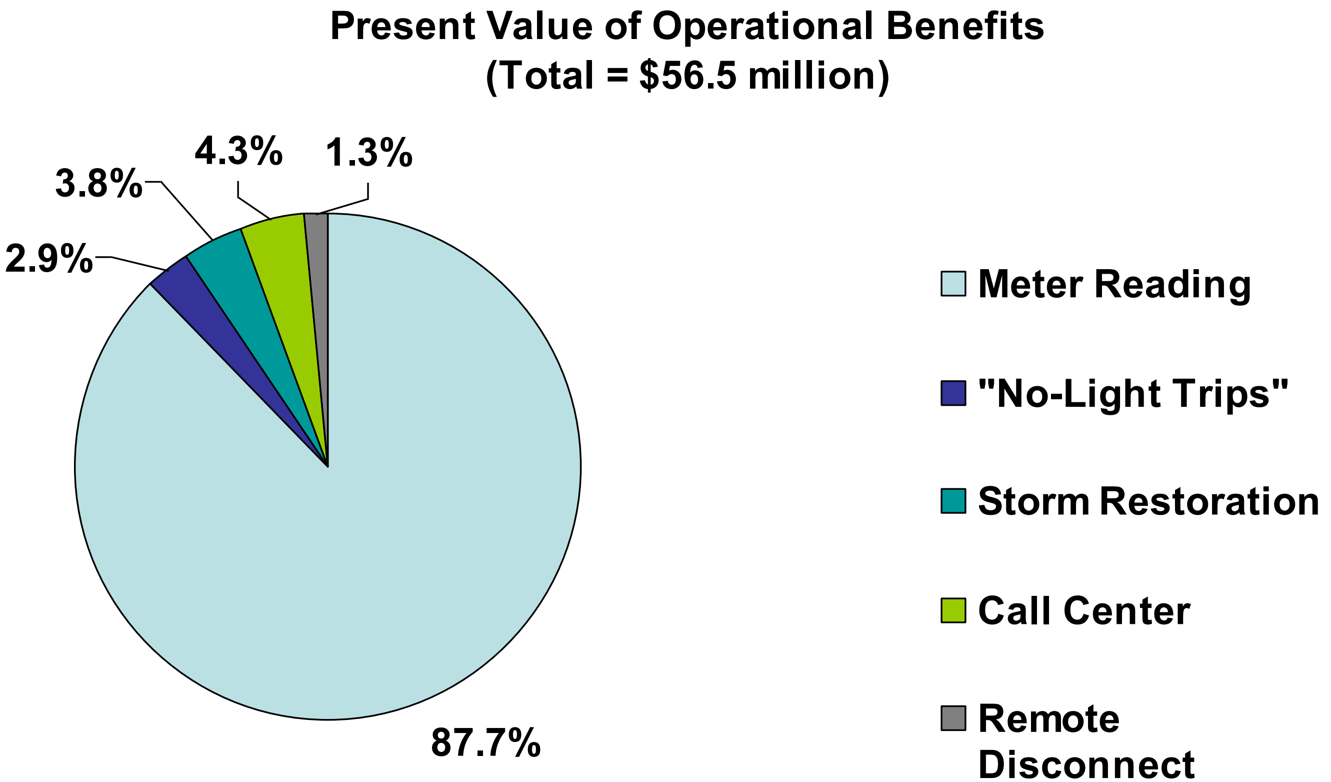
VEC adds about $1.6 million to the overall net benefit estimate



Meter hardware and installation costs account for more than 78% of total costs.

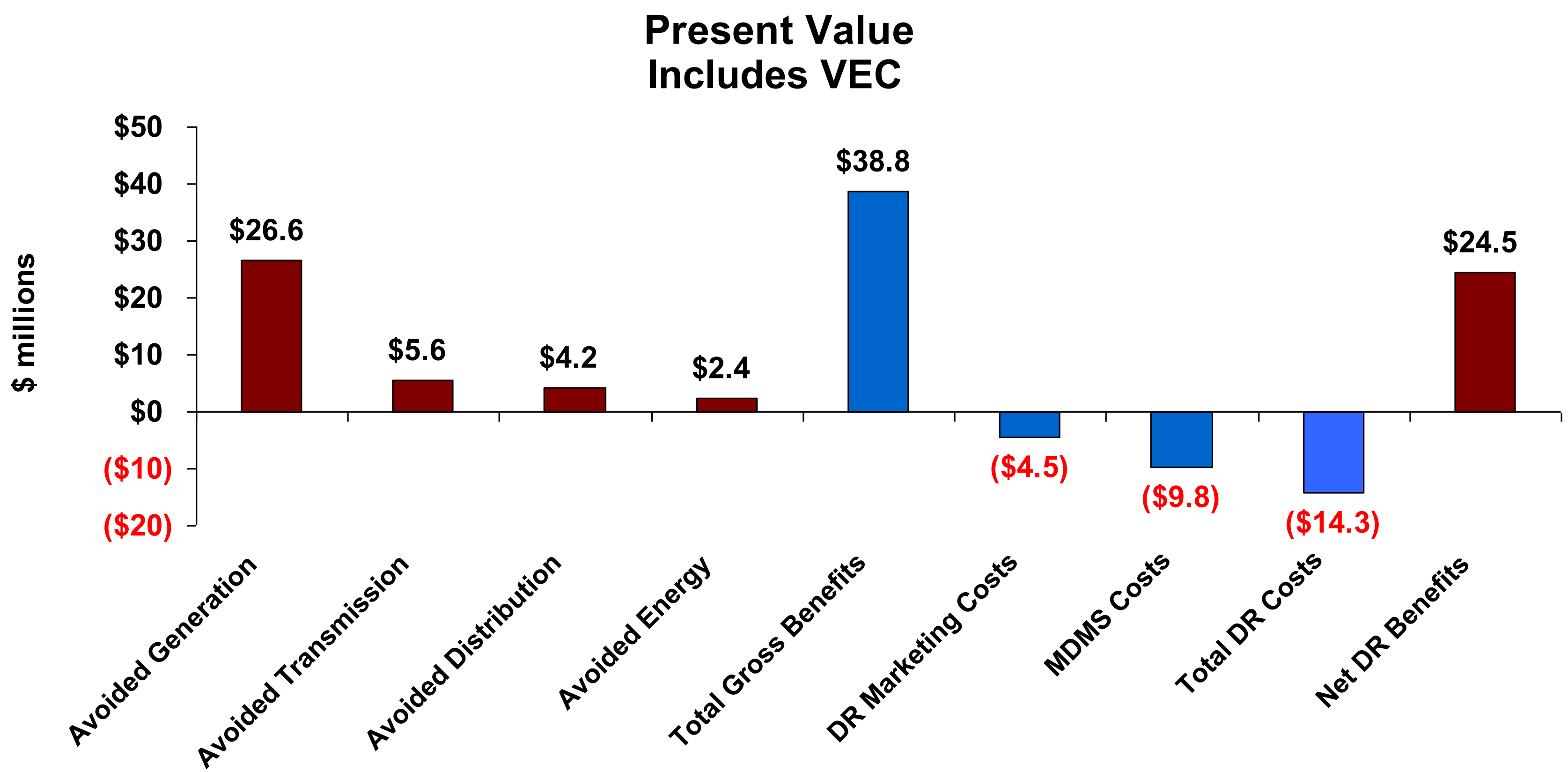


Avoided meter reading costs account for almost 88% of total operational benefits. This share is typically much lower.*

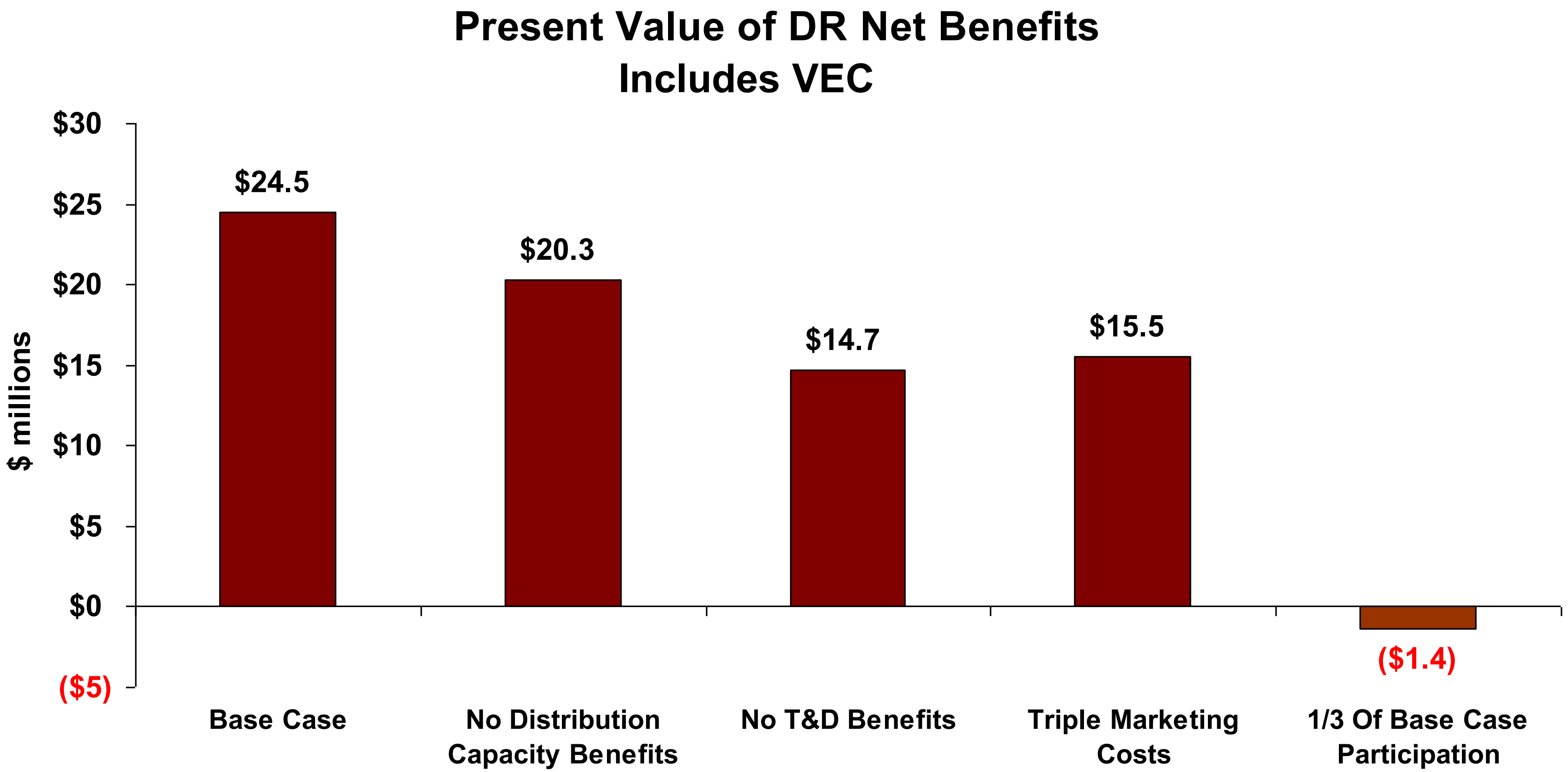


*Additional benefits would likely be identified with more detailed analysis

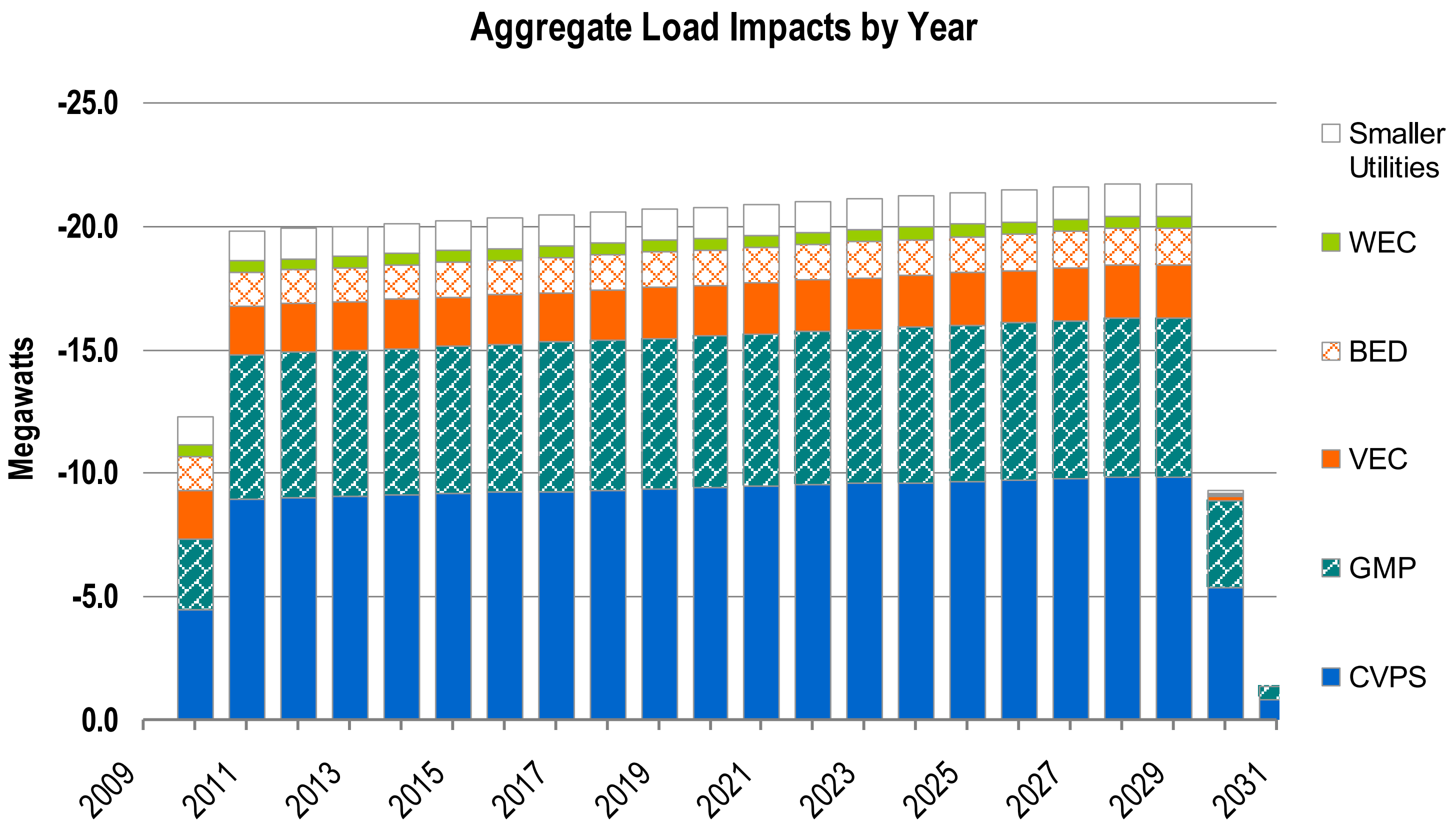
Demand response generates net benefits equal to $24.5 million, with roughly 69% coming from avoided generation capacity costs



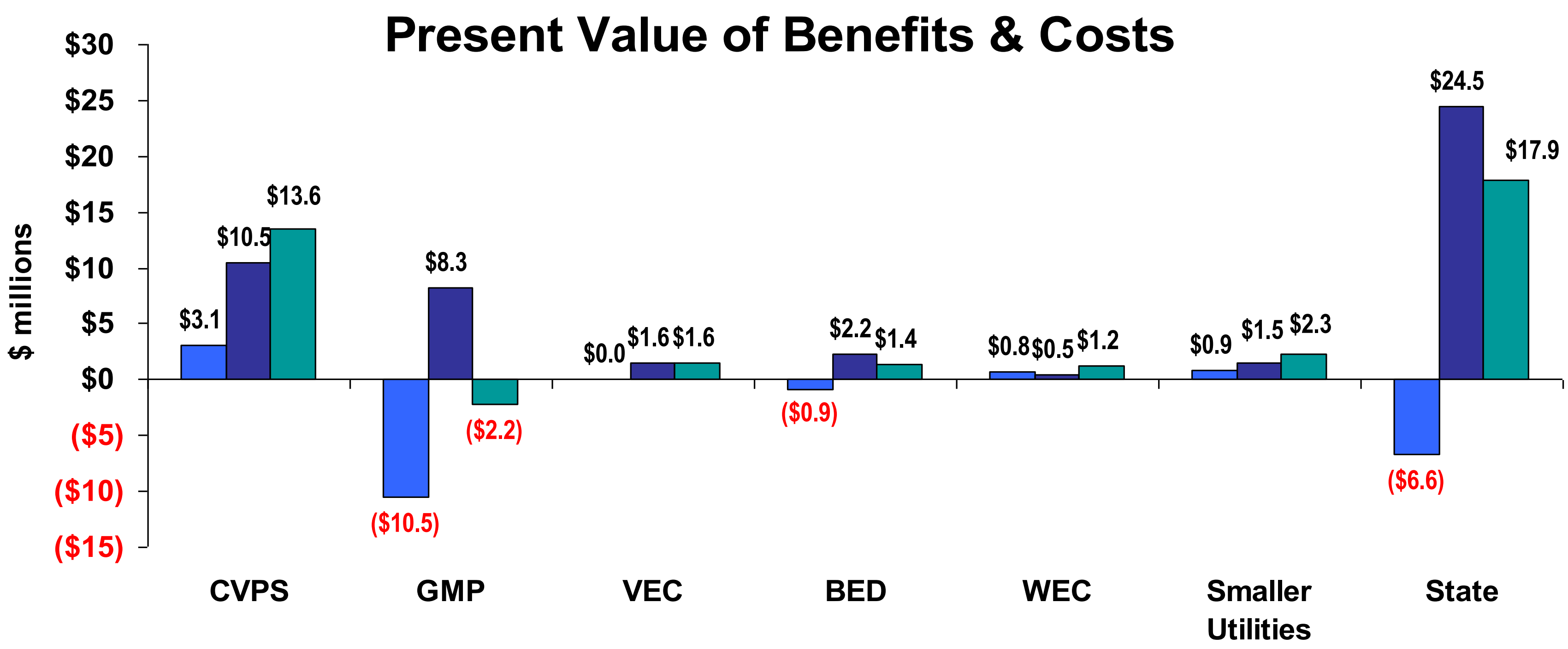
DR net benefits vary with input assumptions but remain positive even with significant changes to most key individual input values



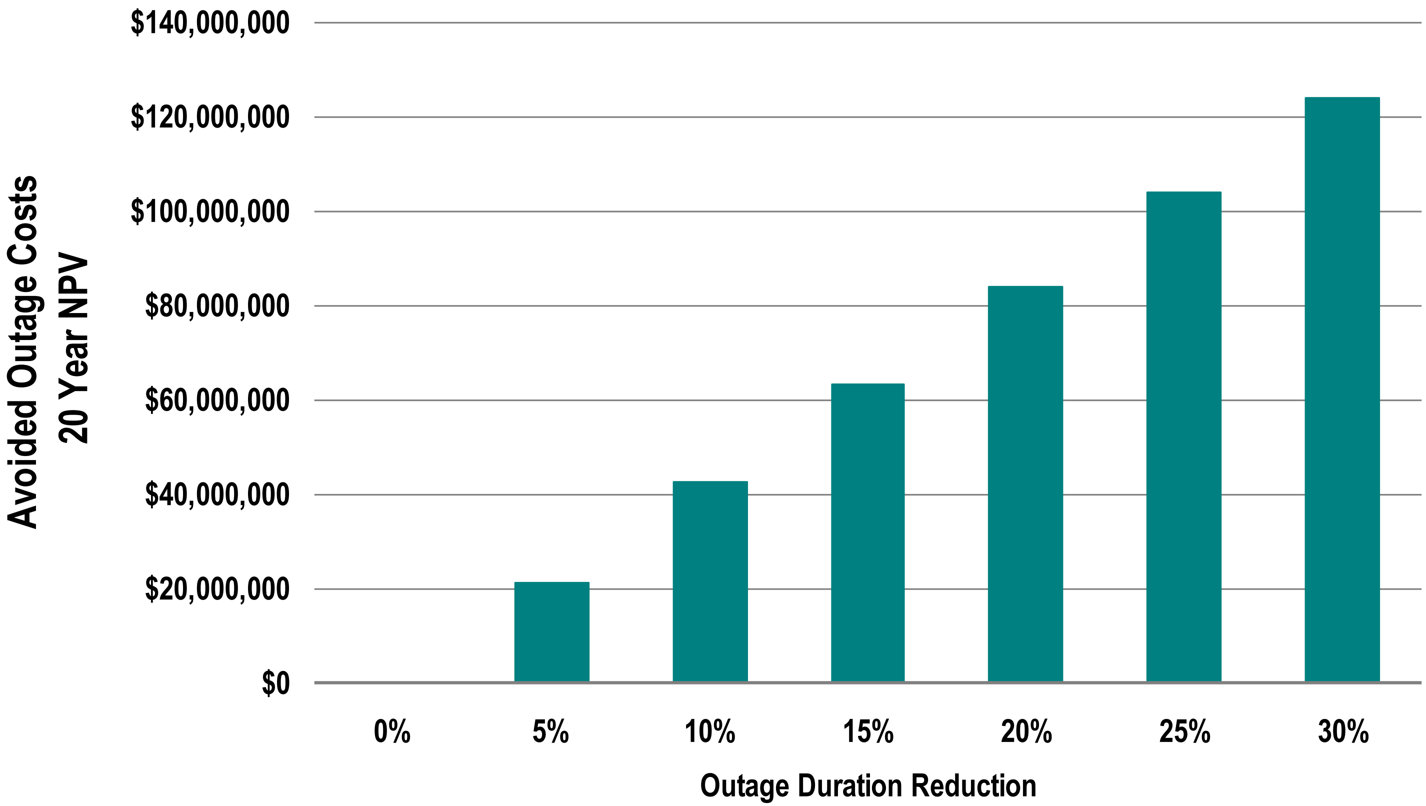
DR can reduce average demand on high demand days by 20 MW starting as early as 2011. This estimate is based on only about 55% of load in VT



As is evident below, "the specifics matter." Costs and benefits vary significantly across companies



Additional benefits in the form of avoided outage costs stemming from reduced outage duration could be substantial. A 5% reduction in outage duration could produce an additional $21.4 million in benefits.



Central Vermont Electric System

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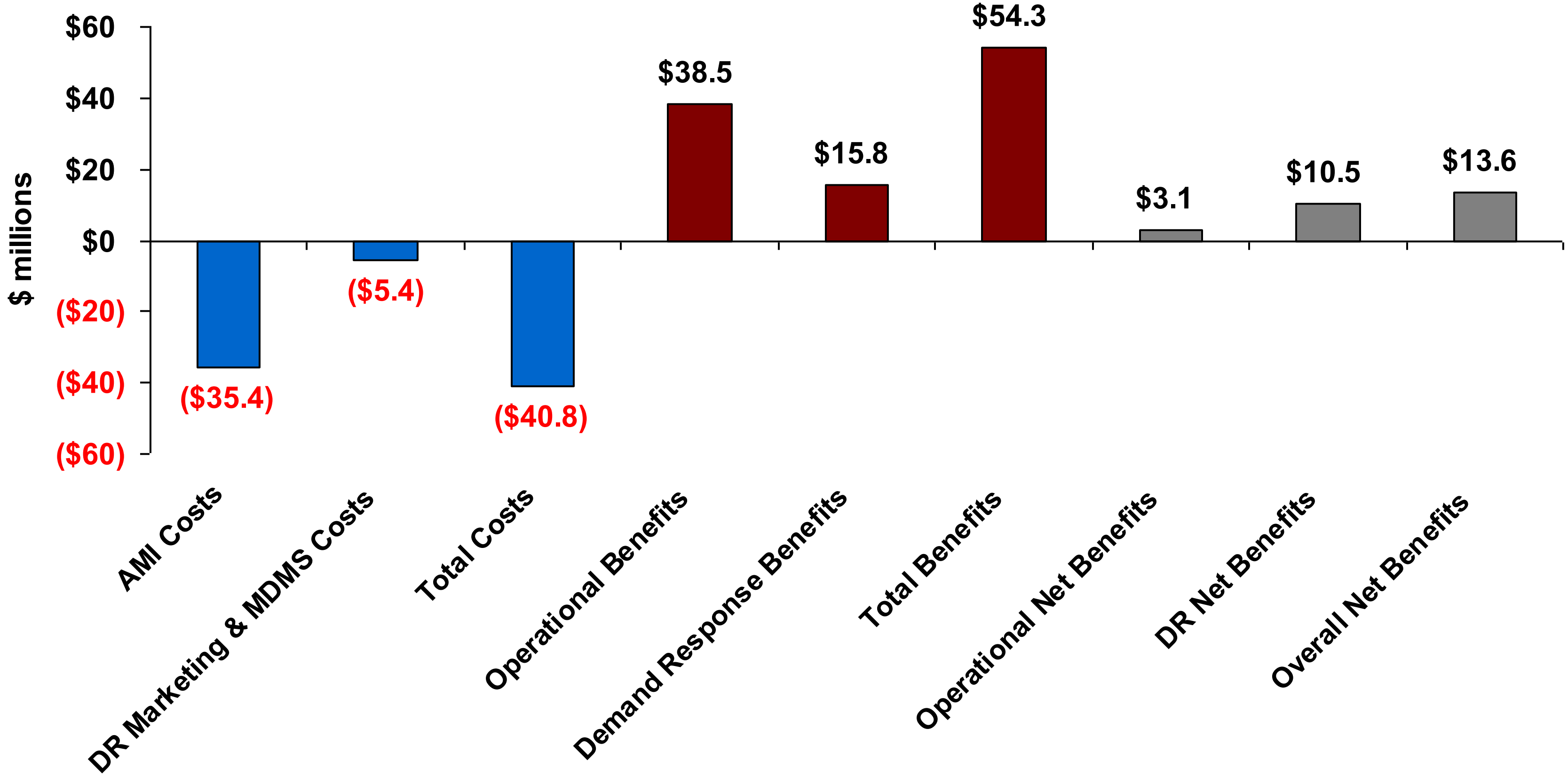
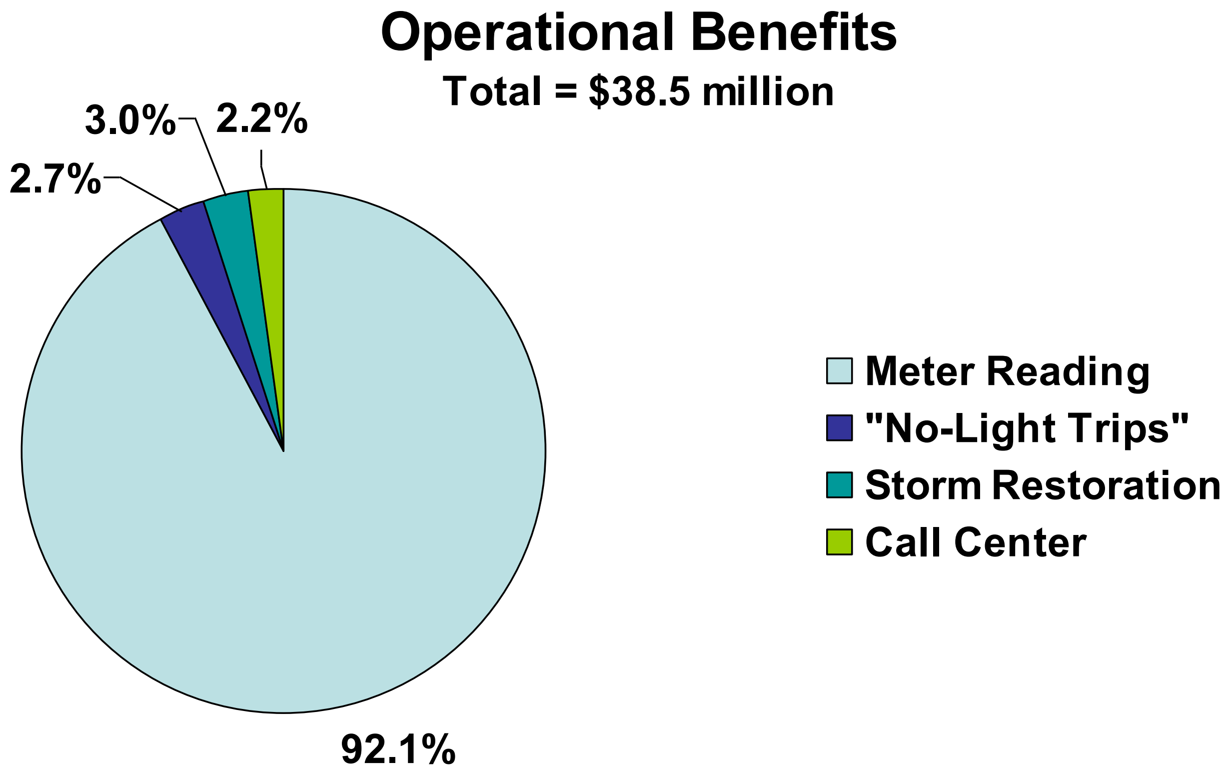
CVPS Characteristics Summary

- Roughly 40% of VT electricity sales and 45% of electricity customers
- Service territory covers 4,700 sq. mi.
- 98 substations
- 70,000 transformers, 20% with only one meter
- Significantly more meters than customers due to separately metered off-peak water heating
- 350,000 calls per year, about 1/3 storm related
- Analysis showed that Mesh was the least cost technology option

The CVPS business case is strongly positive, with operational net benefits = $3.1 million and overall net benefits = $13.6 million



Avoided meter reading costs account for more than 90% of total operational benefits*



*Additional benefits would likely be identified with more detailed analysis

CVPS's business case is quite robust across a wide range in key input assumptions

- CVPS shows positive net operational benefits
- A five-fold increase in marketing costs would still produce positive overall net benefits equal to more than $6 million
- A five-fold increase in marketing costs and a 40% reduction in assumed awareness/notification rates would produce roughly a breakeven overall net benefit estimate

Green Mountain Power

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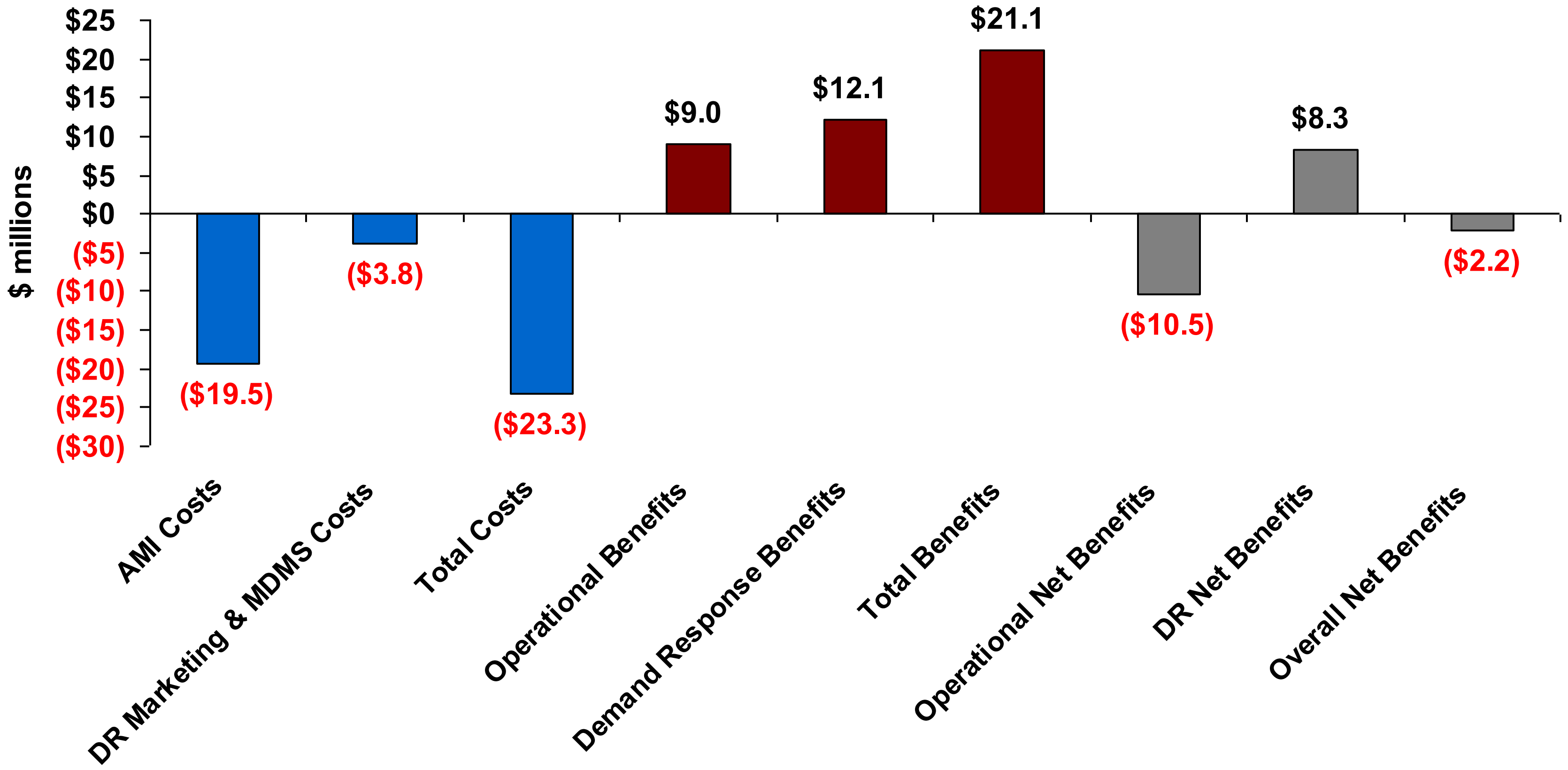
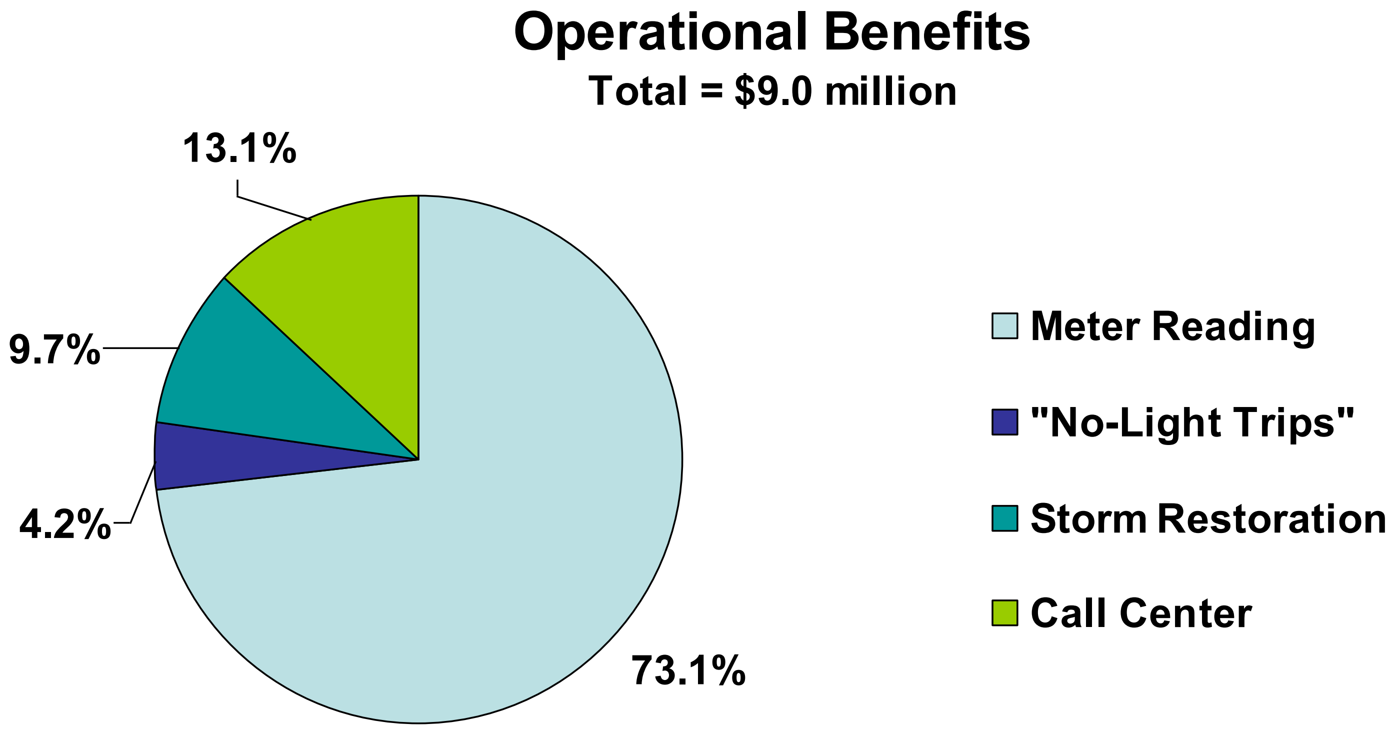
GMP Characteristics Summary

- Accounts for roughly 1/3 of electricity sales and 1/4 of the customers in VT
- 52 substations
- 160,000 calls per year, with more than 75% non-storm related
- Reads meters every other month and 30% of meters are read using mobile AMR
  - Meter reading costs are quite low
- Mesh was the least cost technology option

GMP's business case is negative even when DR benefits are included, although additional operational benefits are likely and could create a breakeven business case



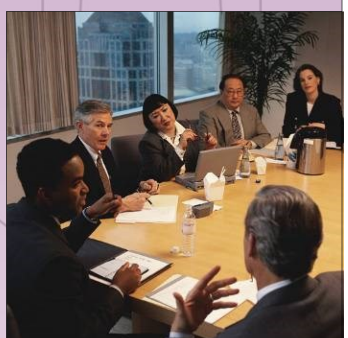
Avoided meter reading costs account for almost 75% of total operational benefits*



*Additional benefits would likely be identified with more detailed analysis

GMP's business case is the least robust of all the utilities

- Reliability and environmental benefits at GMP would create positive overall benefits equal ~$2.3m
- If GMP were to qualify for the 20% Federal grant, overall net benefits would equal ~$1.2m
- If default, dynamic pricing was implemented at GMP, overall net benefits could exceed $3m
- Implementing AMI and instituting monthly meter reading at GMP would likely generate additional customer and operational benefits



Vermont Electric Coop

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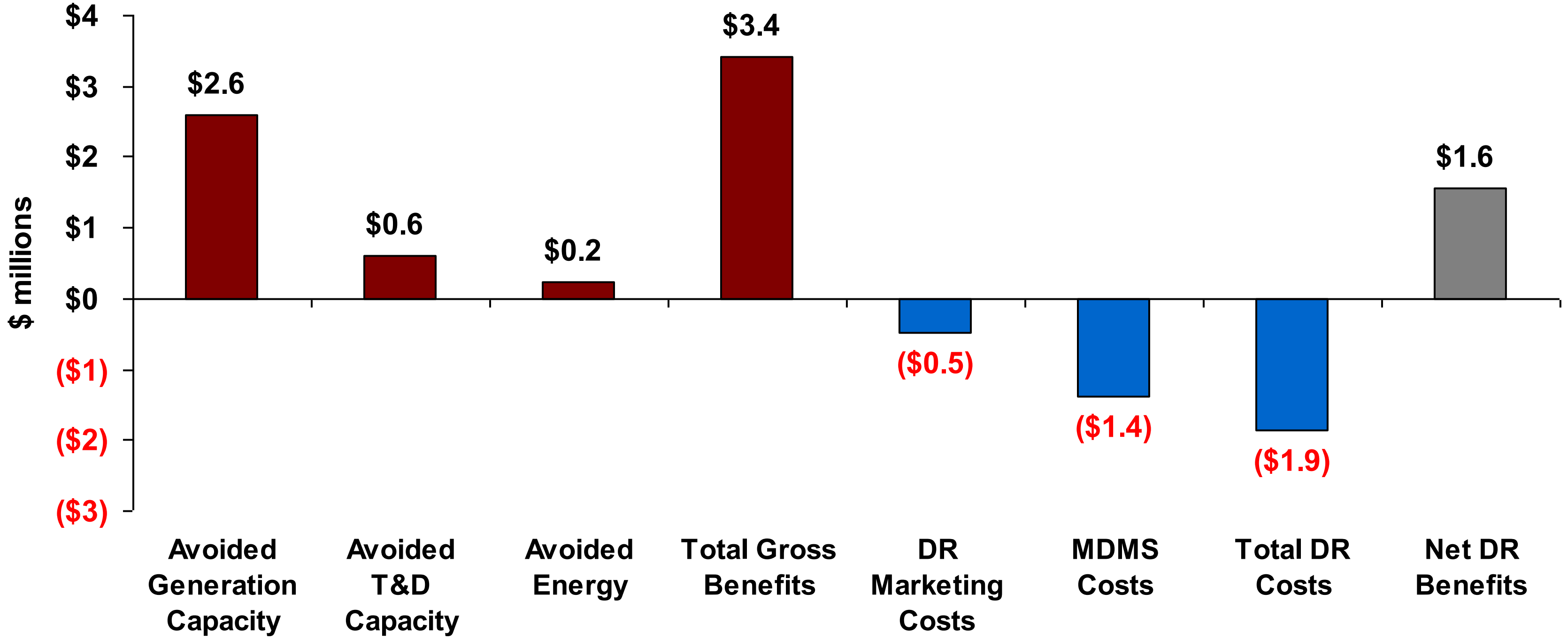
VEC Characteristics Summary

- Accounts for about 8% of Vermont electricity sales and about 11% of customers
- VEC is already installing AMI meters
  - Analysis only looked at the incremental costs and benefits associated with time-based pricing
  - We assumed that MDMS services would be acquired on an outsourcing basis to support time-based billing

The VEC analysis only examined DR benefits & costs, as VEC is already of installing AMI meters.* Net DR benefits equal $1.6m. Reliability benefits would increase this total to $4.2m.

Demand Response Benefits & Costs



*We have assumed that VEC has not included an MDMS in it's current plans and one would be needed to support DR

Burlington Electric Department

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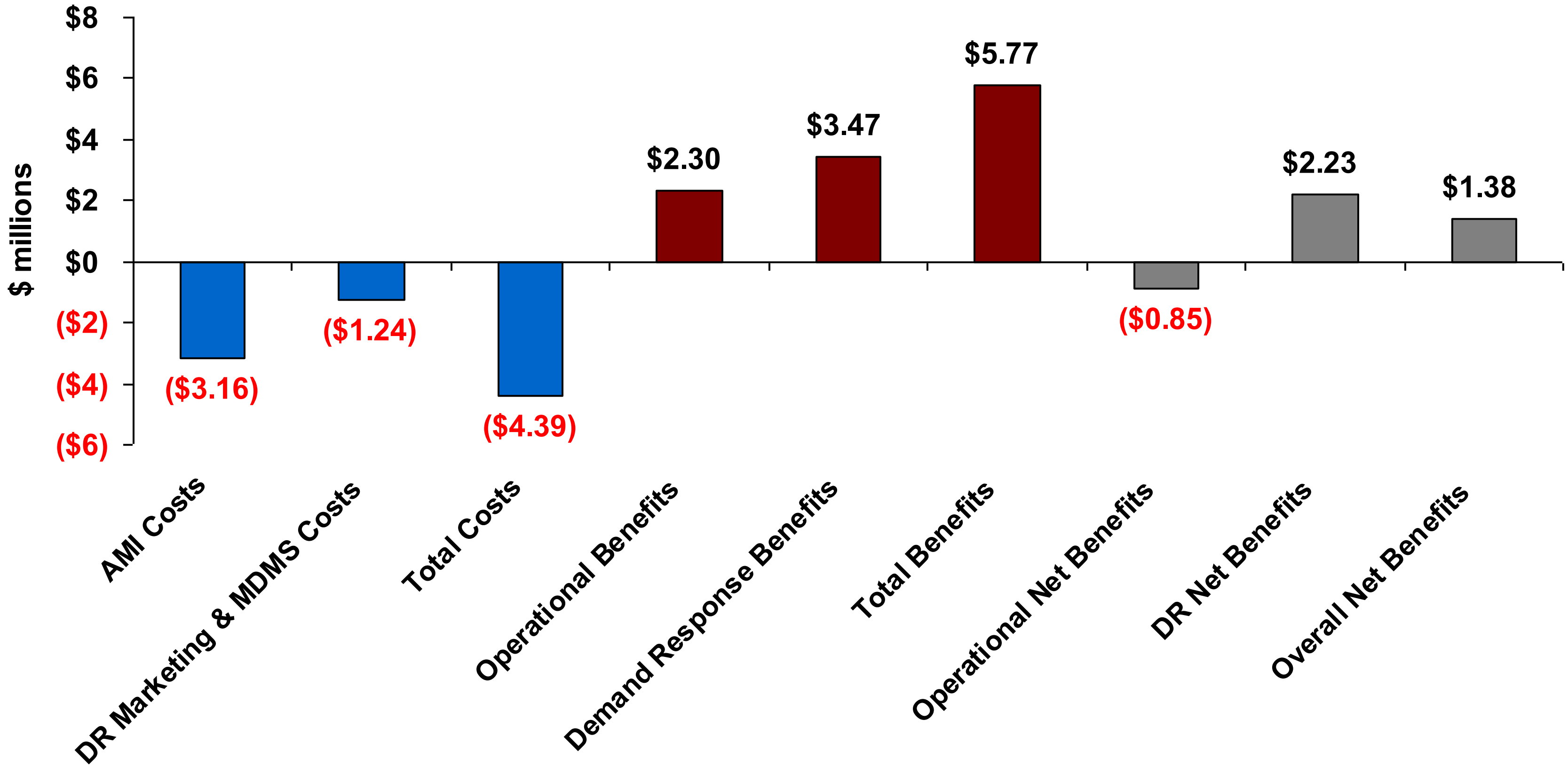
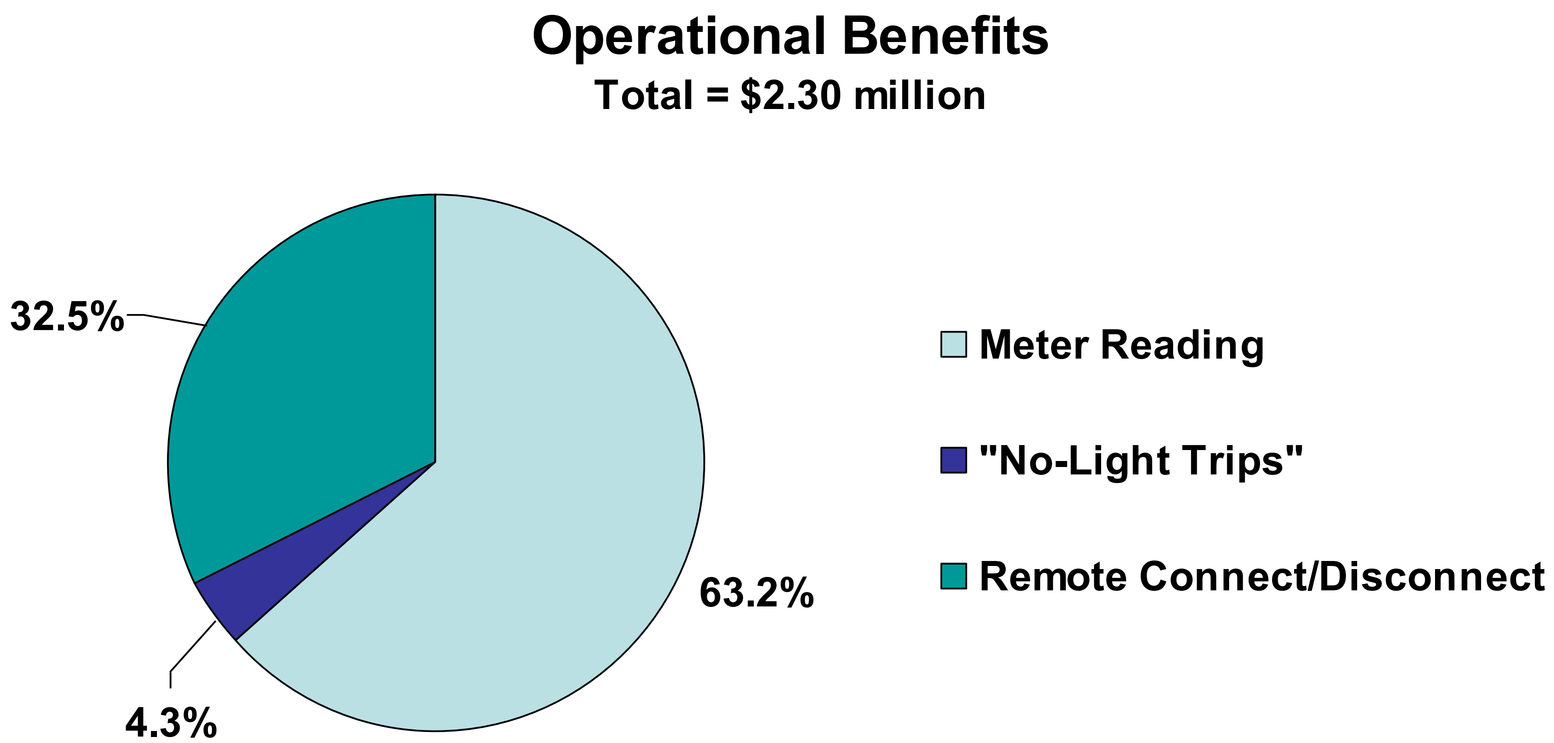
BED Characteristics Summary

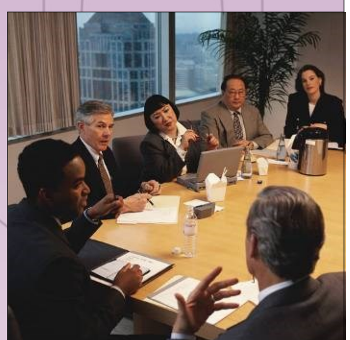
- Accounts for roughly 6% of customers and electricity use
- Very compact service territory, only 16 sq. mi.
- The commercial sector has a much larger share of load than for the other utilities
- 7 substations
- Fewer outages than other utilities
- Has a high turnover rate given large student population
  - Examined costs and benefits of remote connect/disconnect under partial and full deployment scenarios
  - Benefits exceeded costs for the partial deployment scenario
- Mesh proved to be the least cost technology

The BED business case shows a small negative value for operational net benefits but is positive when DR is included. Reliability benefits would add an additional $440k.



Partial deployment of remote disconnect functionality improves BED's business case and accounts for almost 1/3 of operational benefits





Washington Electric Cooperative

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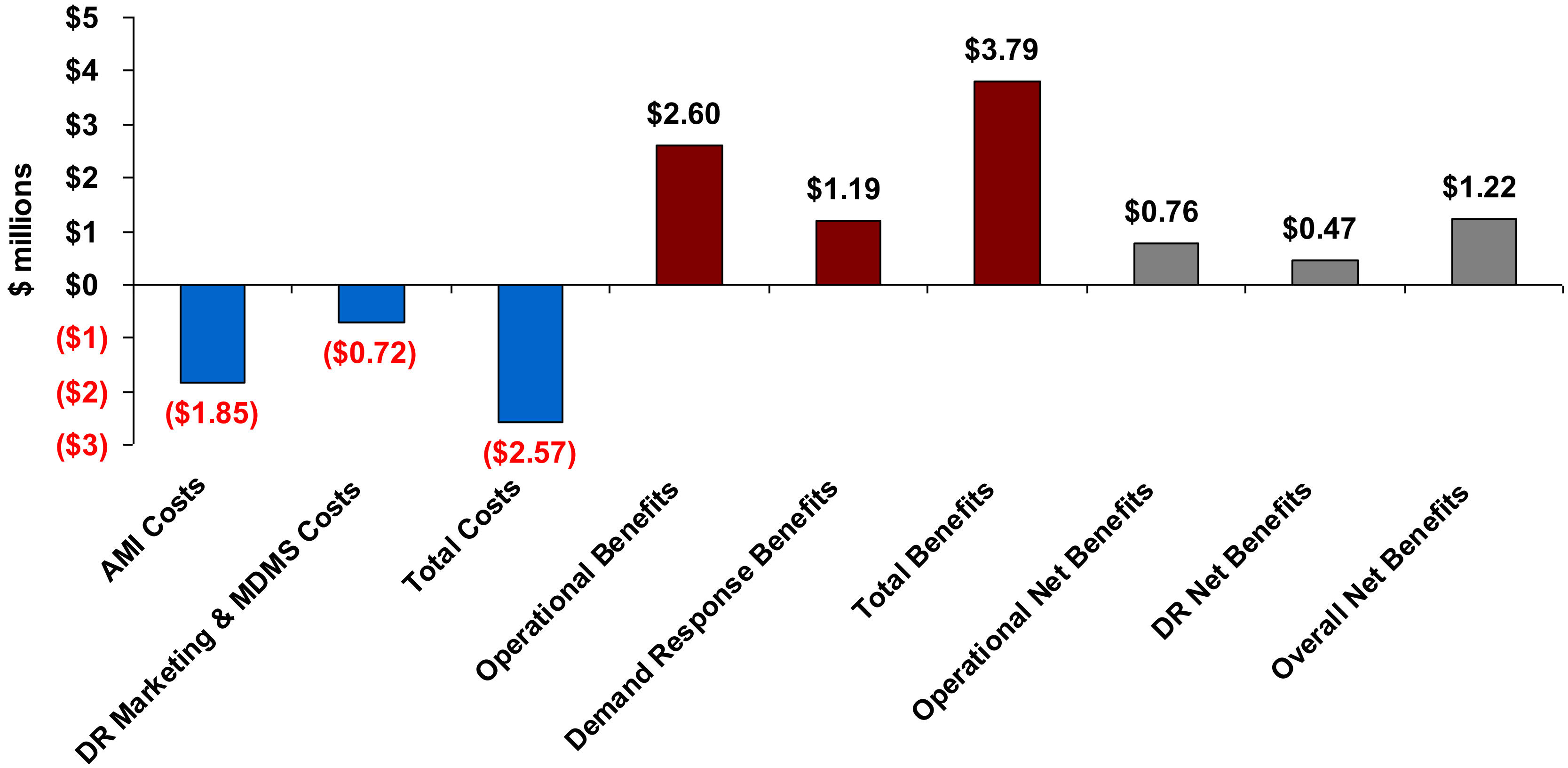
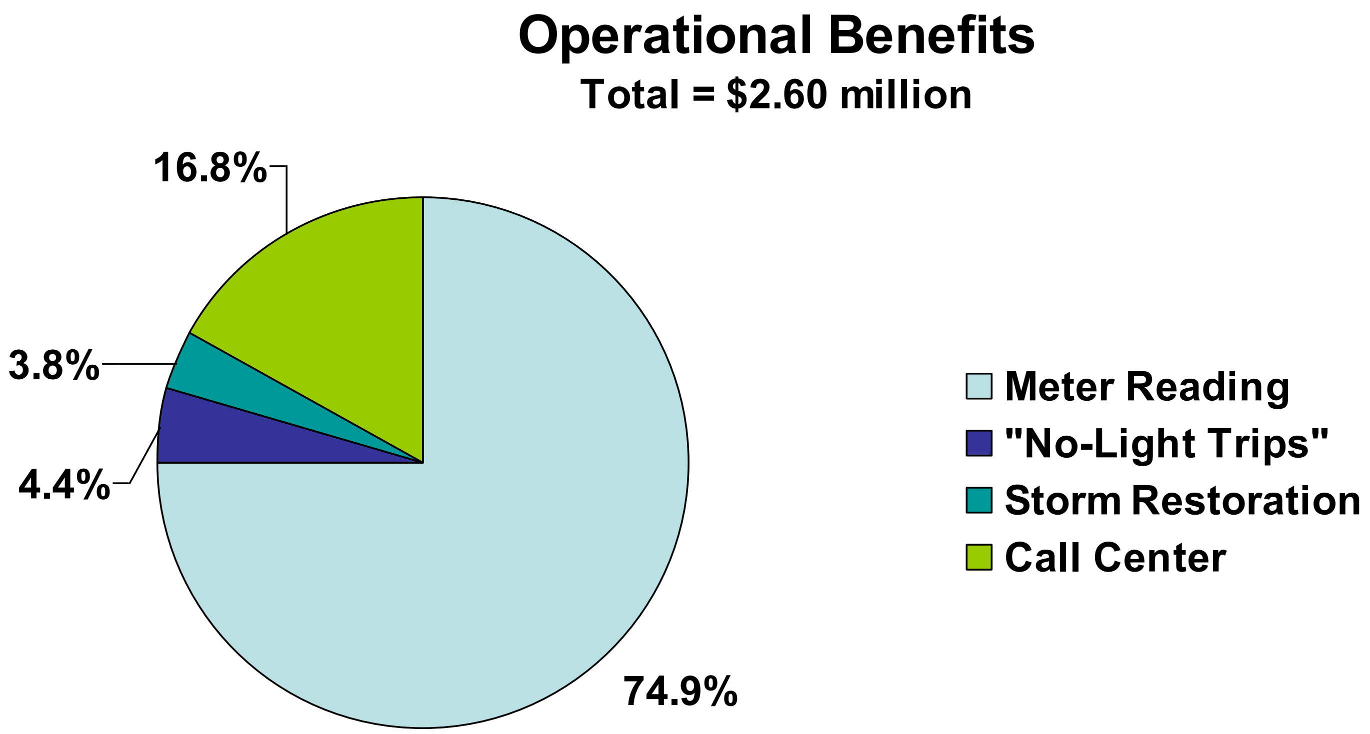
WEC Characteristics Summary

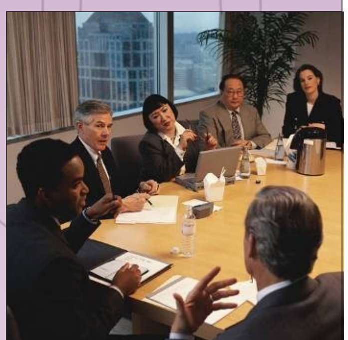
- Accounts for only about 3% of Vermont's customers and 1% of Vermont's electricity use
- Roughly 10,000 customers, nearly all of which are residential accounts
- 8 substations
- 1,200 sq. mi. service territory with very low customer density
- Meter reading operation is contracted out
- PLC proved to be the least cost technology

WEC's business case shows positive operational net benefits and overall net benefits of $1.2m when DR is included. Reliability would add $0.3m



Avoided meter readings costs account for 75% of total operational benefits. Avoided meter reading benefits of $1.95m alone exceed AMI costs of $1.85m





Small Utility Group

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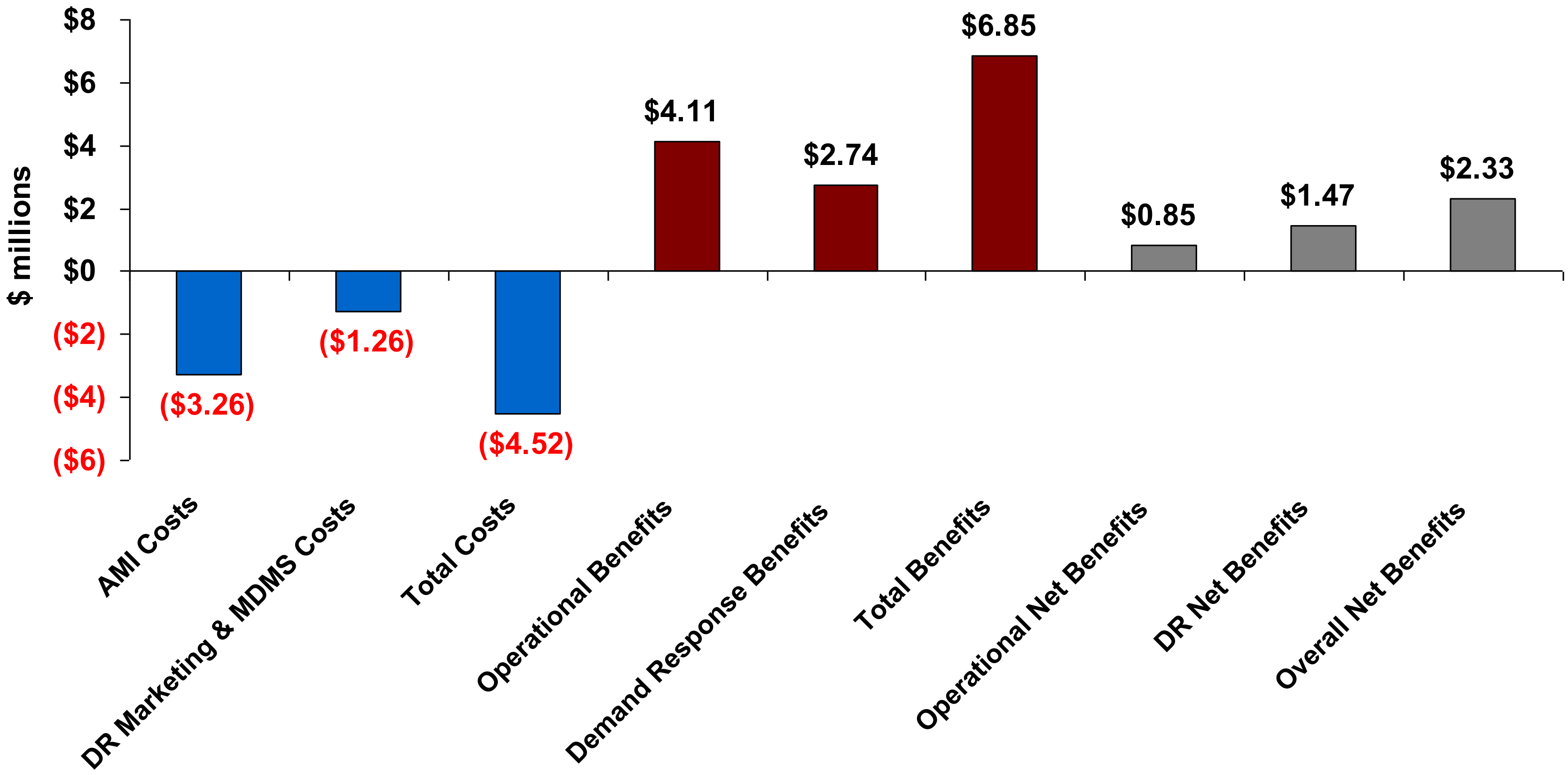
Small utility group summary

- The small utility group consists of Hardwick Lyndonville, Stowe, Morrisville and Ludlow
- Combined, these utilities serve 20,673 customers and deliver 263 GWH of electricity
- The combined service territory is 468 sq. mi.
- Customer density of 44 customers per sq. mi., which is in between that of CVPS and GMP
- Mesh proved to be the least cost technology option
- We assumed that these utilities combined could obtain MDMS and billing services to support time-based pricing at a cost comparable to that of VEC and WEC

The small utility business case has a positive operational net benefit estimate based solely on avoided meter reading costs. DR benefits add to this total & reliability benefits would add $1.6m



Rate Design Issues & Policies

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Smart meters and dumb prices represents bad public policy

- AMI is cost-effective for most utilities in Vermont even in the absence of time-based pricing
- But not using AMI systems to support a more rational pricing strategy would miss a significant opportunity to lower electricity costs in the long run
- The primary objective of time-based pricing is to
  - More accurately reflect costs—everyone pays their fair share
  - Improve economic efficiency—have prices influence customer decisions
  - Too much focus on the first objective can undermine the second
  - A tariff that perfectly reflects the cost of supply may be too opaque to influence consumer behavior

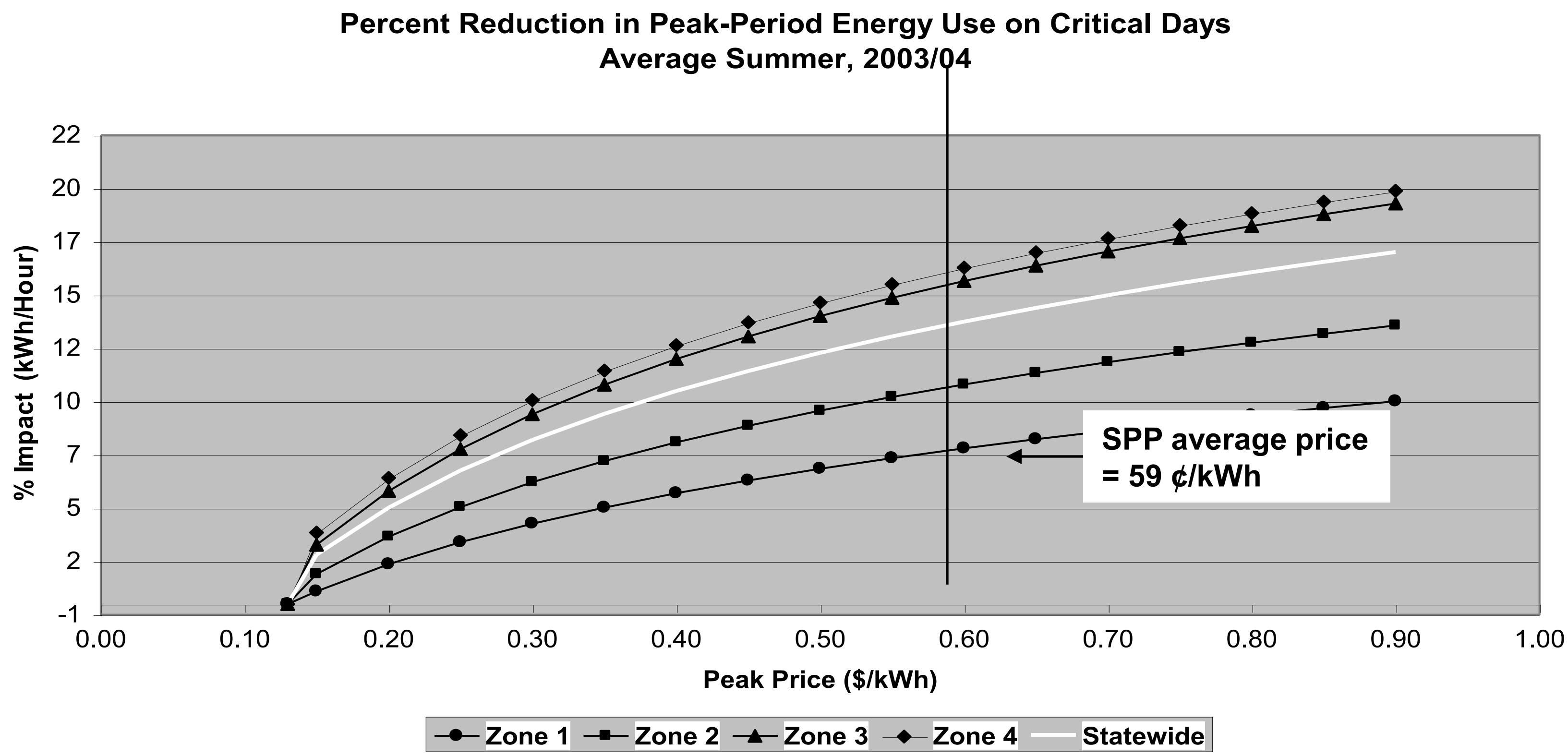
Increasing block rates versus time-based rates—substitutes or complements

- Increasing block pricing can more accurately reflect long-run marginal costs and more accurately allocate costs across consumers compared with a constant price
- By raising the average cost for large users, block pricing could reduce energy use at the margin
  - We are not aware of any empirical studies that show the impact of block pricing on energy use
- Does nothing to reduce usage during high cost peak periods
- It is difficult or impossible for customers to know what the marginal price is
  - Do not know if the next kWh costs 10 cents or 15 cents
  - Face one price in the beginning of the month and another at the end of the month
  - Do not know the average price until after the fact (when the bill is sent)

Time based pricing may be more transparent than block pricing

- Easy to communicate the relative prices and time periods
  - Refrigerator magnets
  - Informative bills
- With dynamic rates that include notification, the notification is a potentially frequent opportunity to remind customers about time periods and relative prices
- Empirical studies show that time-based prices have a very modest conservation effect and can even increase energy use slightly
- Time-based pricing and block pricing are not substitutes
  - Both can be applied simultaneously in the same tariff

Higher peak period prices will decrease peak demand, up to a point. Above some threshold, consumers may not reduce demand much further. In NSW, Australia, no difference between demand at $1.50/kWh & at $2.00/kWh.



Revenue neutrality has implications for rate design

- The number of peak period hours impacts both peak and off-peak prices
  - A very high price for a large number of hours will require very low (potentially even negative) off-peak prices
  - Critical peak prices or peak-time rebates in effect for 75 to 100 hours can be much higher than TOU prices and still keep off-peak prices rational
- Given the same peak-period price, seasonally revenue neutral tariffs will have lower off-peak prices than annually revenue neutral tariffs

Revenue neutral tariff options and resulting demand response impacts

			TOU		CPP		CPP-TOU	
		PURE PTR	*Annual Neutrality*	*Seasonal Neutrality*	*Annual Neutrality*	*Seasonal Neutrality*	*Annual Neutrality*	*Seasonal Neutrality*
STARTING PRICES								
	Avg Summer Price	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194	$0.1194
	Avg Winter Price	$0.1195	$0.1195	$0.1195	$0.1195	$0.1195	$0.1196	$0.1196
	Fixed Monthly Charge	$11.64	$11.64	$11.64	$11.64	$11.64	$11.64	$11.64
NEW PRICES								
1	**CPP day peak price**	$0.8692	$0.2396	$0.2396	$0.8692	$0.8692	$0.8692	$0.8692
2	**Summer weekday peak price**	$0.1195	$0.1139	$0.0946	$0.1117	$0.0881	$0.2396	$0.2396
3	**Summer Off-peak**	$0.1195	$0.1139	$0.0946	$0.1117	$0.0881	$0.0796	$0.0642
4	**Non-summer peak**	$0.1195	$0.1139	$0.1195	$0.1117	$0.1195	$0.2396	$0.2396
5	**Non-summer off-peak**	$0.1195	$0.1139	$0.1195	$0.1117	$0.1195	$0.0796	$0.0854
IMPACTS								
12	**Peak Demand**	0.98	0.98	0.98	0.98	0.98	1.01	1.01
13	Peak Demand Change (kW)	-0.10	-0.03	-0.04	-0.10	-0.11	-0.11	-0.12
14	Peak Demand Change (%)	-10.23%	-3.41%	-3.74%	-10.40%	-11.02%	-11.30%	-11.89%
15	**Annual Energy Consumption (kWh)**	6,893.8	6,893.8	6,893.8	6,893.8	6,893.8	6,893.8	6,893.8
16	Change in Energy Consumption (kWh)	-9.1	1.4	0.8	8.5	9.4	13.4	14.0
17	Change in Energy Consumption (%)	-0.13%	0.02%	0.01%	0.12%	0.14%	0.19%	0.20%

[1] Rate structure: summer includes June, July, and Augus with peak period of 12-6. For TOU non-summer peak period is from 4-10 pm
[2] Pricing rules: TOU price equal 2X old price for both seasons. CPP and PTR apply only to summer. CPP price equals old price plus 75c. PTR equals base price plus 75c.

Peak-time rebates versus critical peak prices

- PTR is a pay-for-performance tool, not a cost allocation tool
- Evidence so far suggests that PTR and CPP options produce similar demand response per customer
- PTR typically offers more flexibility in terms of frequency of use
- PTR should have higher participation rates on an “opt-in” basis, potentially significantly higher
  - “Carrot only” versus “carrot-and-stick” signals
  - Eliminates any risk of higher bills
- It is likely that PTR will produce greater aggregate impacts than CPP because of the difference in participation rates

Opt-in versus opt-out implementation

- Opt-out (or default pricing) is a voluntary rate—IT IS NOT MANDATORY!
- Opt-out will produce higher participation rates
  - Potentially 80% for opt-out versus 10-20% for opt-in
- Evidence suggests that opt-out WILL NOT generate a ratepayer revolt
  - Customers like time-based rates once they try them
  - There will be other options available for those who don't
- For the same level of participation, opt-out will have much lower marketing costs
- Evidence suggests that time-based pricing does not adversely affect low income consumers and may lower their bills more on a proportionate basis than for high income users
- There are many reasons to consider some form of time-based pricing as the default pricing option in Vermont

Conclusions and Recommendations

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Implementation of AMI and time-based pricing in Vermont is likely to reduce costs

- Overall net benefits are significantly positive
- Excluding GMP, operational net benefits are positive overall for the 8 utilities examined
  - The analysis considered a very limited set of operational benefits
  - Additional analysis is likely to turn BED positive based on operational savings alone but probably wouldn't achieve that goal with GMP
  - Additional analysis of operational benefits is likely to turn GMP positive when DR benefits are considered
- The Energy Independence Act could improve business cases for all utilities, but there is a lot of uncertainty about how this will be applied
- Implementation of default, time-based pricing would significantly strengthen the business cases of all utilities
  - Default pricing is likely to have higher participation rates and unlikely to create a ratepayer revolt
  - Current results are based on 55% of load in VT

Based on this analysis, VT should continue to investigate and pursue AMI and time-based pricing

- It would be easy to say, “Isn’t that nice” and go back to business as usual
- Our recommendations in the following areas are intended to avoid that temptation
  - AMI technology implementation
  - Ancillary capabilities enabled through advanced meters
  - Data management to support time based pricing
  - Rate design
  - Regulatory concerns

AMI technology implementation

- Initiate more detailed, utility-specific analysis
  - GMP, BED and WEC
  - Smaller utilities working together
- CVPS should continue to move forward with their analysis & planned implementation and determine whether the planned schedule can be accelerated
- Vermont should establish minimum functionality requirements
- A working group of small utilities should be formed to examine how cooperative planning and implementation, including consideration of shared networks & MDMS and joint purchasing, can lower costs

AMI technology implementation

- Commission a statewide propagation study that could be used by each utility to refine cost estimates and obtain bids
- Monitor the rules associated with allocation of limited funds associated with the 20% grant provision of the Energy Independence Act
- Examine costs and benefits of AMI for water meters for utilities that jointly read electricity and water meters

Ancillary capabilities enabled through AMI

- Investigate the merits of AMI investments that support enabling technology
  - Home Area Networks
  - In-home displays
  - Control technologies
- Examine advantages and disadvantages of various options
  - Open standards
  - Parallel networks, including the Internet

Data management to support time-based pricing

- AMI implementation should include MDMS and billing support for time-based pricing
- VEC should acquire the necessary capabilities to support time-based pricing
- A working group of Vermont's 15 smallest utilities should be formed to examine options for obtaining these capabilities jointly or in groups

Rate design

- Determine whether alternative pricing strategies that take advantage of AMI are warranted
- Once the relevant MDMS and billing support is available, VEC should implement a pricing pilot focused primarily on understanding participation rates for various pricing options under different marketing/implementation strategies (e.g., opt-in versus opt-out, etc.)

Rate design

- Consider moving to default time-based pricing
- Initiate investigation into variety of issues associated with time-based pricing
  - What are the underlying principles guiding rate design
  - Type of pricing (e.g., TOU, CPP, etc.)
  - Differential impact on various customer segments
  - Understandability of various options
  - Magnitude of hedging premium for non-time varying rate option
  - Interplay with block pricing and energy efficiency initiatives
  - Operational challenges for small utilities
  - Implications for revenue stability

Regulatory concerns

- The risk of stranded costs associated with current meters is a barrier to implementation
  - Vermont should examine ways of mitigating this risk
  - There are provisions in the Energy Independence Act indicating that utilities should continue to be allowed to recover undepreciated costs of existing meters in the rate base
- Risk of Monday-morning quarterbacking
  - What if meter functionality changes or costs fall significantly shortly after making investment—will utilities be subject to disallowances?

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